ALASKA FEDERAL OFFSHORE
Descriptions of Geologic Plays
1995 National Resource Assessment
U.S. Minerals Management Service

ST. GEORGE BASIN ASSESSMENT PROVINCE
(C. Drew Comer and Bruce M. Herman)

Four plays with geophysically-mapped prospects have been identified in the St. George basin assessment province: (1) the St. George graben, (2) the south platform, (3) the north platform, and (4) the Pribilof basin.

Play 1 (UASG0101[1]): St. George Graben: The St. George graben trends northwest-southeast for over 200 miles, is 10- to 25-miles wide, and contains as much as 40,000 feet of Cenozoic strata (Marlow and others, 1976). Potential hydrocarbon traps include faulted anticlines, upthrown fault traps along the border faults of the graben, drape of Tertiary strata over basement fault blocks, stratigraphic onlap onto the basement, and possible pinchout of sands. Five exploratory wells, including one sidetrack hole, were drilled in the graben. All wells were plugged and abandoned with only minor gas shows encountered.

The best reservoir rocks encountered in the graben are Oligocene sandstones. The Arco Y-0511 well encountered fine-grained Oligocene sandstones in beds ranging from 10- to 40-feet thick for a gross total of 460 feet. Porosities ranged from 20 to 30 percent and permeabilities ranged from 20 to 130 millidarcies. The Exxon Y-0527 well had Oligocene sandstones in beds ranging from 5- to 20-feet thick for a gross total of 185 feet. The Exxon Y-0530 and the Chevron Y-0519 wells, also located in the graben, had no sandstones of reservoir quality. Porosity loss with depth tends to be very high in the St. George basin province because the rocks have a high content of volcanic rock fragments which are diagenetically altered to zeolite and clay minerals with burial.

The source-rock potential is poorly known for the graben, but the COST No. 2 well, located along its southeastern margin, had relatively low TOC values in the Cenozoic and Mesozoic sections (Turner and others, 1984b). The kerogen types identified were gas-prone and the top of the oil window occurs at approximately 12,000 feet. Other unexplored areas of the graben are much deeper and may have better source-rock potential. The Arco Y-0511 well penetrated the northern boundary fault of the graben and recovered samples of Jurassic shales that had TOC values of 0.5 to 2.0 percent. The visual kerogen examination reported a high

[1]*The “UA” Code is the "Unique Assessment Identifier" for each play, and is the principal guide to GRASP data files.*

percentage of amorphous material. If oil-prone source rocks are present in the St. George basin province, they probably occur in Jurassic strata. The province is underlain by the Mesozoic Peninsular terrane which extends from the Cook Inlet area, where Middle Jurassic strata are known to have generated oil (Magoon and Claypool, 1981; Magoon and Anders, 1992).

Play 2 (UASG0201). South Platform Play The south platform includes the area south of the St. George graben to the continental slope and east of Pribilof Canyon. This stable shelf area contains as much as 10,000 feet of nearly flat-lying strata, separated from acoustic basement by an angular unconformity. The overlying strata range from middle Eocene to Pleistocene and were mostly deposited in a marine-shelf environment. The basement at the COST No. 1 well consists of basaltic igneous rocks, but Mesozoic and lower Tertiary sedimentary rocks occur below the acoustic basement unconformity elsewhere. Potential traps include anticlinal structures within the acoustic basement, drape of Tertiary sands over basement highs, fault-bounded traps, and stratigraphic onlap onto basement highs. Five exploratory wells and one COST well were drilled in the south platform play area, all of which were plugged and abandoned with only minor gas shows encountered.

The best reservoir-rock potential is in the Oligocene section. The COST No. 1 well contained individual sandstone beds greater than 150 feet thick, with an aggregate total of 1,200 feet. Porosities were as high as 25 percent and permeabilities were as high as 37 millidarcies (Turner and others, 1984a). Permeabilities were as high as 300 to 400 millidarcies in Oligocene sandstones in the Shell Y-0454 well.

Source-rock potential in the south platform area appears to be poor. The sediments were deposited under oxidizing conditions and are low in TOC. Only gas-prone kerogen types were present in samples from the COST No. 1 well, and the rocks were thermally immature. The oil window occurs at approximately 12,000 feet, so any hypothesized thermally mature hydrocarbon source must involve rocks that lie below the acoustic basement unconformity, the latter generally shallower than 10,000 feet in this play area.

Play 3 (UASG0301). North Platform Play : The north platform extends north of the St. George graben for about 10 to 25 miles. This area contains 3,000 to 10,000 feet of Cenozoic sedimentary rocks over the acoustic basement unconformity. The basement just north of the graben is probably composed of Mesozoic and lower Tertiary sedimentary rocks. Farther north, less than 3,000 feet of Cenozoic strata occur over igneous basement. Potential traps include stratigraphic onlap onto basement highs, anticlinal structures within the basement, drape of Tertiary strata over basement highs, and fault-bounded traps. No exploratory wells have tested prospects in the north platform play.

Oligocene sandstones probably have the best reservoir-rock potential, based on seismic correlation from well control in the graben to the south. The oil window occurs at approximately 12,000 feet, so thermally mature source rocks would have to be present in basement strata for the north platform play to be viable. The best source-rock potential is probably in Jurassic strata, based on data from the Arco Y-0511 well, which was drilled in the graben but penetrated the north-bounding fault.

Play 4 (UASG0401). Pribilof Basin Play : The Pribilof basin is a half graben that is about 30-miles wide, trends northwest-southeast for about 70 miles, and contains as much as 20,000 feet of Cenozoic sedimentary rocks (Scholl and Hopkins, 1969). It lies between St. George Island and the continental slope west of Pribilof Canyon. The area has never been offered for leasing and no wells have been drilled there. Potential traps include anticlines in the acoustic basement with drape in overlying strata, upthrown fault traps over tilted basement blocks, and stratigraphic onlap.

There are no reservoir-rock or source-rock data for the Pribilof basin. However, seismic data suggest that the basal strata were deposited when the surrounding area was emergent (Comer and others, 1987). Therefore, restricted circulation in the early Tertiary may have been conducive to organic preservation, and strata with good source-rock potential may have been deposited. The oil window probably occurs at about 12,000 feet, so the basal strata should be thermally mature.

OIL AND GAS ENDOWMENTS OF ST. GEORGE BASIN PLAYS

Risked, Undiscovered, Conventionally Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI * CODE)	OIL (BBO)			GAS (TCFG)		
		F95	MEAN	F05	F95	MEAN	F05
1.	St. George Graben (UASG0101)	0.000	0.059	0.155	0.000	1.007	2.743
2.	South Platform (UASG0201)	0.000	0.034	0.152	0.000	0.898	4.325
3.	North Platform (UASG0301)	0.000	0.025	0.101	0.000	0.676	2.674
4.	Pribilof Basin (UASG0401)	0.000	0.017	0.070	0.000	0.414	1.502
	FASPAG AGGREGATION	***0.000***	***0.135***	***0.414***	***0.000***	***2.995***	***9.716***

* *Unique Assessment Identifier, code unique to play.*

REFERENCES CITED

Comer, C.D., Herman, B.H., and Zerwick, S.A., 1987, Geologic report for the St. George Basin Planning Area, Bering Sea, Alaska: U.S. Minerals Management Service OCS Report 87-0030, 84p.

Magoon, L.B., and Anders, D.E., 1992, Oil-to-source-rock correlation using carbon-isotope data and biological marker compounds, Cook Inlet-Alaska Peninsula, Alaska, *in* Moldowan, M.J., Albrecht, P., and Philp, R.P., eds., Biological markers in sediments and petroleum:

New Jersey, Prentice-Hall, p. 241-274.

Magoon, L.B., and Claypool, G.E., 1981, Petroleum geology of Cook Inlet basin, an exploration model: American Association of Petroleum Geologists Bulletin, v. 65, p. 1043-1061.

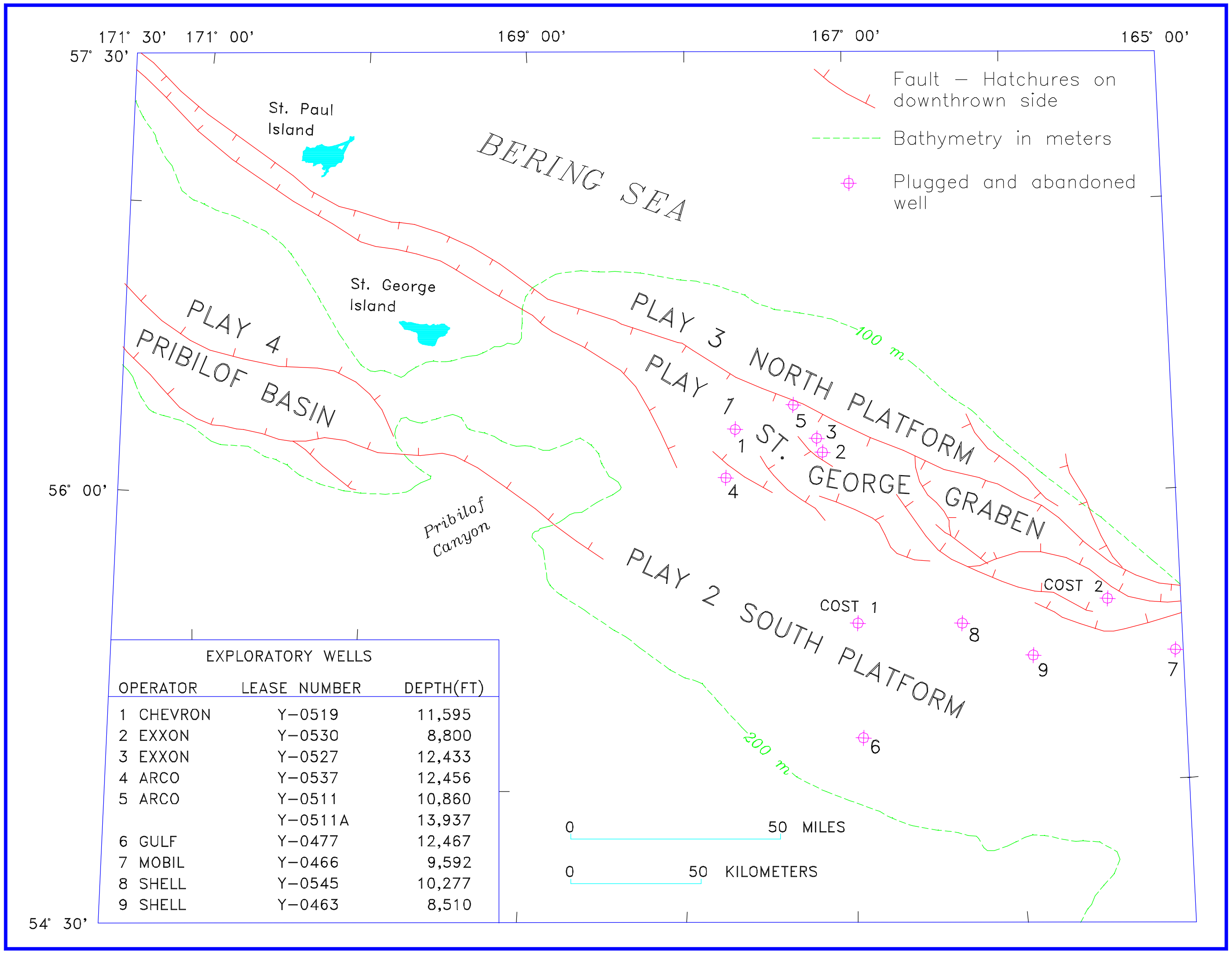
Marlow, M.S., Scholl, D.W., Cooper, A.K., and Buffington, W.C., 1976, Structure and evolution of the Bering Sea shelf south of St. Lawrence Island: American Association of Petroleum Geologists Bulletin, v. 60, p. 161-183.

Scholl, D.W., and Hopkins, D.M., 1969, Newly discovered Cenozoic basins, Bering Sea shelf, Alaska: American Association of Petroleum Geologists Bulletin, v. 53, p.2067-2078.

Turner, R.F., McCarthy, C.M., Comer, C.D., Larson, J.A., Bolm, J.G., Banet, A.C., Jr., Adams, A.J., 1984a, Geological and operational summary, St. George Basin COST No. 1 well, Bering Sea, Alaska: U.S. Minerals Management Service OCS Report MMS 84-0016, 105p.

Turner, R.F., McCarthy, C.M., Comer, C.D., Larson, J.A., Bolm, J.G., Flett, T.O., and Adams, A.J., 1984b, Geological and operational summary, St. George Basin COST No. 2 well, Bering Sea, Alaska: U.S. Minerals Management Service OCS Report MMS 84-0018, 100p.

ST. GEORGE BASIN - MAP OF PLAYS



OPERATOR	LEASE NUMBER	DEPTH(FT)
1 CHEVRON	Y-0519	11,595
2 EXXON	Y-0530	8,800
3 EXXON	Y-0527	12,433
4 ARCO	Y-0537	12,456
5 ARCO	Y-0511	10,860
	Y-0511A	13,937
6 GULF	Y-0477	12,467
7 MOBIL	Y-0466	9,592
8 SHELL	Y-0545	10,277
9 SHELL	Y-0463	8,510

EXPLANATION OF DATA TABLES FOR ST. GEORGE BASIN ASSESSMENT PROVINCE

RESULTS

LOG-N PARAMS (PORE)	Key mathematic parameters that describe log-normal probability distributions for volume of hydrocarbon-bearing rock, in acre-feet, for each play as reported in the **PORE** module of **GRASP**.
mu	Natural logarithm of F50 value of log-normal distribution for volume of hydrocarbon-bearing rock, or "μ", for the subject play. **mu** = ln F50. [Note: distribution **mean** = $e^{(mu + 0.5[sig. sq.])}$.]
sig. sq.	The variance of the log-normal distribution for volume of hydrocarbon-bearing rock, or "σ^2", for the subject play. **sig. sq.** = $\{\ln [0.5((F50/F16)+(F84/F50))]\}^2$.
N (MPRO)	Number of hydrocarbon pools calculated for the plays by the **MPRO** module of **GRASP** from inputs for probability distributions of prospect numbers and geologic chances of success (approximately the product of play and prospect chances of success) . The maximum (**Max**) number of pools for each play was entered into the **MONTE1** module of **GRASP** to fix the number of pools aggregated to calculate play resources.
Reserves	Sums of recoverable oil and gas volumes for pools within the play, including both proven and inferred reserve categories. A "prop" entry indicates that the reserve data are proprietary.
BCF	Billions of cubic feet of gas, recoverable, at standard (surface) conditions (here fixed at a temperature of 60° Fahrenheit or 520° Rankine, and 14.73 psi atmospheric pressure).
MMB	Millions of barrels of oil, recoverable, at standard (surface) conditions.
Undiscovered Potential	Risked, undiscovered, conventionally recoverable oil and gas resources of the play, here reported at **Means** of probability distributions.

EXPLANATION OF DATA TABLES FOR ST. GEORGE BASIN ASSESSMENT PROVINCE

Mean Pool Sizes of Ranks 1 to 3 Unrisked (or conditional) mean volumes of recoverable oil and gas in the three largest pools in the play.

PLAY INPUT DATA

F100.....F00 Fractiles for values within probability distributions entered to **GRASP** for calculations of play resources. Four-point distributions (F100, F50, F02, F00) generally indicate that calculations were conducted using log-normal mathematics. Eight-point distributions generally indicate that calculations were conducted using Monte Carlo mathematics. Choice of mathematic approach was in most cases the option of the assessor.

Prospect Area Maximum area of prospect closure, or area within spill contour, in acres. Probability distributions for prospect areas were generally based on distributions assembled independently for each play from large numbers of prospects mapped with seismic reflection data.

Trap Fill Trap fill fraction, or fraction of prospect area in which the reservoir is predicted to be saturated by hydrocarbons.

Pool Area Areal extent of hydrocarbon-saturated part of prospect, in acres. Calculated using **PRASS**, or **SAMPLER** module of **GRASP**, to integrate input probability distributions for prospect areas and trap fill fractions.

Pay Thickness Thickness of hydrocarbon-productive part of reservoir within pool areas, in feet. Probability distributions for prospect areas, trap fill fractions, and pay thicknesses are integrated in the **PORE** module of **GRASP**, to calculate a probability distribution for volume of hydrocarbon-bearing rock, in feet, within the play as reported above under **LOG-N PARAMS (PORE)** .

EXPLANATION OF DATA TABLES FOR ST. GEORGE BASIN ASSESSMENT PROVINCE

Oil Yield (Recov. B/Acre-Feet)	Oil, in barrels at standard (surface) conditions, recoverable from a volume of one acre-foot of oil-saturated reservoir in the subsurface. Oil yield probability distributions were generally calculated in a separate exercise using **PRASS** to integrate input probability distributions for porosities, oil saturations, oil shrinkage factors (or "Formation Volume Factors"), and oil recovery efficiencies.
Gas Yield (MMCF/Ac.-Ft.)	Gas, in millions of cubic feet at standard (surface) conditions, recoverable from a volume of one acre-foot of gas-saturated reservoir in the subsurface. Distributions were generally calculated in a separate exercise using **PRASS** to integrate input probability distributions for porosities, gas saturations, reservoir pressures, reservoir temperatures (in degrees Rankine), gas deviation ("Z") factors, combustible fractions (that exclude noncombustibles such as carbon dioxide, nitrogen, etc.), and gas recovery efficiencies.
Solution Gas-Oil Ratio (CF/B)	Quantity of gas dissolved in oil in the reservoir that separates from the oil when brought to standard (surface) conditions, in cubic feet recovered per barrel of produced oil.
Gas Cond. (B/MMCF)	Quantity of liquids or condensate dissolved in gas in the reservoir that separates from the gas when brought to standard (surface) conditions, in barrels recovered per million cubic feet of produced gas.
Number of Prospects.......	Probability distributions for numbers of prospects in plays, generally ranging from minimum values (F99) representing the numbers of mapped prospects, to maximum values (F00) that include speculative estimates for the numbers of additional prospects that remain unidentified (generally stratigraphic prospects, geophysically indefinite prospects, or prospects expected in areas with no seismic coverage).

EXPLANATION OF DATA TABLES FOR ST. GEORGE BASIN ASSESSMENT PROVINCE

<u>Probabilities for Oil, Gas, or Mixed Pools</u>

Oil (OPROB)	Fraction of hydrocarbon pools that consist entirely of oil, with no free gas present. Typically, an undersaturated oil pool.
Gas (GPROB)	Fraction of hydrocarbon pools consisting entirely of gas, with no free oil present.
Mixed (MXPROB)	Fraction of hydrocarbon pools that contain both oil and gas as free phases, the gas usually present as a gas cap overlying the oil.
Fraction of Net Pay to Oil (OFRAC)	When a hydrocarbon pool is modeled as a mixed case, with both oil and gas present, the fraction of pool volume that is saturated by oil in the subsurface.
Play Chance Success	Probability that the play contains <u>at least one</u> pool of technically-recoverable hydrocarbons (that would flow into a conventional wellbore in a flow test or during production).
Prospect Chance Success	The fraction of prospects within the play that are predicted to contain hydrocarbon pools, <u>given the condition</u> that at least one pool of technically-recoverable hydrocarbons occurs within the play.

<u>Play Type (E-F-C)</u>	Play classification scheme.
E	**Established** play, in which significant numbers of fields have been discovered, providing the assessor with data for pool size distributions and reservoirs sufficient to allow the assessor to model the play with confidence.
F	**Frontier** play, where exploration activities are at an early stage. Some wells have already been drilled to test the play concept but no commercial fields have been established.

EXPLANATION OF DATA TABLES FOR ST. GEORGE BASIN ASSESSMENT PROVINCE

C	**Conceptual** play, hypothesized by analysts based on the subsurface geologic knowledge of the area. Such plays remain hypothetical and the play concept has not been tested.

ST. GEORGE BASIN

Play				Log-N Params. PORE		N (MPRO)		Reserves		Undiscovered Potentia	
				Ac/Ft	Ac/Ft	No. Pools		Gas	Oil	Gas	Oil
No.	Area	UAI Code	Name	mu	sig. sq.	Mean	Max	(BCF)	(MMB)	(BCF)	(MMB)
1	St. George	UASG0101	St. George Graben	12.60	0.63	5.48	31	0	0	1007	59
2	St. George	UASG0201	South Platform	13.10	3.08	1.78	16	0	0	898	34
3	St. George	UASG0301	North Platform	13.05	1.79	1.86	15	0	0	676	25
4	St. George	UASG0401	Pribilof Basin	13.67	0.72	1.29	10	0	0	414	17

PLAY		MEAN POOL SIZES OF RANKS 1 TO 3						INPUT DATA					
		Pool #1		Pool #2		Pool #3		Prospect Area (Acres)					
		Gas	Oil	Gas	Oil	Gas	Oil						
No.	Name	(BCF)	(MMB)	(BCF)	(MMB)	(BCF)	(MMB)	F100	F95	F75	F50	F25	F05
1	St. George Graben	523	19.9	302	11.6	219	8.3	976	4113		12497		39916
2	South Platform	2292	86.5	557	21.5	248	9.5	66	1792		24450		333680
3	North Platform	796	30.1	278	10.7	153	5.8	118	2608		18271		127981
4	Pribilof Basin	497	19	252	9.7	174	6.6	2043	11871		35838		108189

PLAY		INPUT DATA										
		Prospect Area (Acres)			Trap Fill (Dec. Frac.)							
No.	Name	F02	F01	F00	F100	F95	F75	F50	F25	F05	F02	F01	F00
1	St. George Graben			163650	0.06	0.12		0.20		0.33			0.71
2	South Platform			9007800	0.02	0.07		0.12		0.23			0.63
3	North Platform			2841696	0.06	0.12		0.20		0.33			0.71
4	Pribilof Basin			628665	0.06	0.12		0.20		0.33			0.71

ST. GEORGE BASIN

PLAY		INPUT DATA													
		Pool Area (Acres)									Pay Thickness (Feet)				
No.	Name	F100	F95	F75	F50	F25	F05	F02	F01	F00	F100	F95	F75	F50	F25
1	St. George Graben	101	666		2532		9762			43552	48	80		120	
2	South Platform	9	199		3227		53099			1668000	44	85		145	
3	North Platform	13	469		3860		33285			673851	48	80		120	
4	Pribilof Basin	250	1963		7192		27448			262039	48	80		120	

PLAY		INPUT DATA															
		Pay Thickness (Feet)				Oil Yield (Recov. B/Acre-Foot)								Gas Yield (MMCF/Ac.-Ft)			
No.	Name	F05	F02	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	St. George Graben	181			303	28	59		104		185		382	0.032	0.117		0.332
2	South Platform	246			477	38	80		143		256		532	0.038	0.120		0.303
3	North Platform	181			303	39	80		141		251		519	0.037	0.109		0.255
4	Pribilof Basin	181			303	31	65		116		205		424	0.049	0.115		0.229

PLAY		INPUT DATA															
		Gas Yield (MMCF/Ac.-Ft)				Solution Gas Oil Ratio (CF/B)								Gas Cond. (B/MMCF)			
No.	Name	F25	F05	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	St. George Graben		0.940		3.491	89	230		486		1028		2644	20	35		52
2	South Platform		0.763		2.444	64	163		344		725		1856	10	17		25
3	North Platform		0.600		1.760	67	160		321		644		1550	10	17		25
4	Pribilof Basin		0.456		1.084	112	176		253		363		572	20	35		52

ST. GEORGE BASIN

PLAY		INPUT DATA											
PLAY		Gas Cond. (B/MMCF)				Number of Prospects in Play							
No.	Name	F25	F05	F01	F00	F99	F95	F75	F50	F25	F05	F01	F00
	St. George Graben		68		100	16	18		25		52		57
	South Platform		35		50	10	11		17		28		30
	North Platform		35		50	9	10		15		26		27
	Pribilof Basin		68		100	4	5		7		11		12

		INPUT DATA						
		Probabilities for Oil, Gas, or Mixed Pools			Fraction of Net	Play	Prospect	
PLAY		Oil	Gas	Mixed	Pay to Oil	Chance	Chance	Play Type
No.	Name	(OPROB)	(GPROB)	(MXPROB)	(OFRAC)	Success	Success	E - F - C
1	St. George Graben	0.00	0.80	0.20	0.7	0.64	0.30	C
2	South Platform	0.00	0.95	0.05	0.7	0.40	0.20	C
3	North Platform	0.00	0.90	0.10	0.7	0.56	0.20	C
4	Pribilof Basin	0.00	0.80	0.20	0.7	0.56	0.30	C

EXPLANATION OF ST. GEORGE BASIN PLAY SUMMARIES

This section consists of page-size compilations of graphics that summarize the results of ***GRASP*** modeling of the undiscovered, conventionally recoverable oil and gas endowments of each of the plays identified and assessed in the province. Each play summary features a plot for risked cumulative probability distributions for oil, gas, and BOE (gas in oil-equivalent barrels added to oil), a table of results, and a plot showing ranked sizes (oil and gas shown separately) of individual hypothetical pools. These three components of the play summaries are each described below.

Risked Cumulative Probability Distributions for Plays

Each play summary provides, at page top, cumulative probability distributions for risked, undiscovered endowments of conventionally recoverable oil, gas, and BOE. Oil and BOE quantities are shown in billions of barrels (B bbl). Gas quantities are reported in trillions of cubic feet (Tcf). Resource quantities are plotted against "Cumulative frequency greater than %." A cumulative frequency value represents the probability that the play resource endowment will exceed the quantity associated with the frequency value along one of the curves (fig. 0.1). Cumulative frequency values along the curves decrease as resource quantities increase. Accordingly, the cumulative frequencies, or "probabilities for exceedance," of small resource quantities are high, and conversely, the probabilities for exceedance of large resource quantities are low.

The cumulative probability distributions are risked and curves are truncated approximately at the output play chance. In most plays, the output play chance is equal to the input play chance for success. However, in plays with very small numbers of pools, the output play chance may be significantly **lower** than the input play chance for success.

The output play chance is derived from MPRO, a module within ***GRASP*** which uses inputs for geologic chance of success to convert probability distributions for numbers of ***prospects*** to probability distributions for numbers of ***pools***. The output play chance is obtained as a mathematic extrapolation to the probability at which the numbers of pools meets or exceeds zero. In plays with 5 or more pools at the mean, this probability usually equals the input play chance for success. In plays with less than 5 pools at the mean, the zero-pool probability (or output play chance) may be much less than the input play chance. Deviation between the output play chance and the input play chance is greatest in those plays with mean numbers of pools less than unity. Such highly risky plays contribute very little resources to overall province endowments.

Identification numbers beginning with "UA" in the graphics labels are codes unique to each of the plays in the ***GRASP*** data bases.

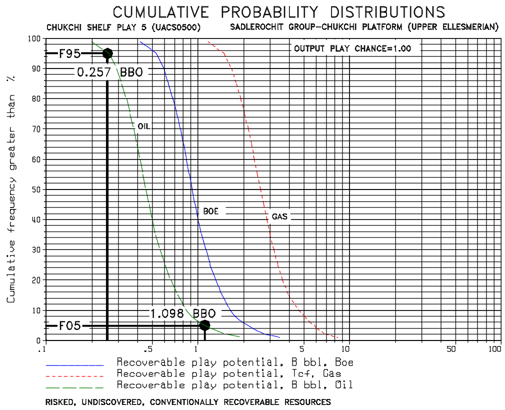
Table for Risked Play Resource Endowments

Each play summary provides, at page center, a table for risked, undiscovered play endowments of oil, gas, and BOE in billions of barrels of oil (BBO) or trillions of cubic feet of gas (TCFG). Quantities are reported at the **mean**, **F95** (a low estimate having a 95-percent frequency of exceedance), and **F05** (a high estimate having a 5-percent frequency of exceedance). Tabulated resource quantities are risked and therefore correspond to points on the cumulative probability distributions shown at page top. For plays with chances for success (play level) less than 0.95, the risked resource quantities reported at **F95** are zero.

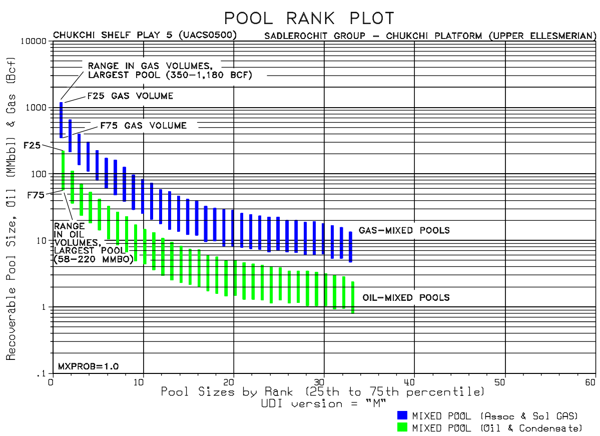
Ranked Pool Size Distributions for Plays

Each play summary provides, at page bottom, a plot showing pool sizes ranked according to size in BOE. The numbers of pools shown in the rank plots correspond to the maximum numbers of pools estimated to occur within the plays. Each pool in a pool rank plot is represented by a pair of adjoining vertical bars. The left bar of each pair represents the range (from **F75** to **F25** in the output probability distribution) of gas recoverable from the pool, and may include non-associated gas from an all-gas pool or associated gas from a gas cap and/or solution gas from oil, depending on pool type. The right bar of each pair represents the range (from **F75** to **F25**) of petroleum liquids recoverable from the same pool, and may include free oil, condensate from a gas cap, or condensate from a gas-only pool.

Volumes are shown in millions of barrels (MMbbl) of oil and billions of cubic feet (Bcf) of gas.



CHUKCHI SHELF PLAY 5 (UACS0500)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**1.478**	**2.993**	**5.823**
OIL (BBO)	**0.257**	**0.537**	**1.098**
BOE (BBO)	**0.530**	**1.069**	**2.125**



The upper graph and the table report the volumes of risked, undiscovered, conventionally recoverable resources for the play. The graph, called a ***cumulative probability distribution***, shows three curves (oil, BOE, and gas) and reports the output play chance at upper right. The output play chance for Chukchi shelf play 5 is 1.0, meaning that there is a 100-percent chance that at least one hydrocarbon pool exists somewhere within the play. To illustrate how to read the graphs, dots have been placed on the ***oil*** curve at cumulative frequency values (vertical axis) of 95-percent and 5-percent. The corresponding oil quantities are 0.257 and 1.098 billions of barrels of oil. Thus, for Chukchi shelf play 5, there is a 95-percent chance that at least 0.257 billion barrels of oil are present and a 5-percent chance that more than 1.098 billion barrels are present. These same oil quantities are listed at F95 and F05 in the table.

The lower graph provides information about pool volumes and is called a ***pool rank plot***. This graph shows two sets of vertical bars, representing the quantities of oil and gas occurring ***together*** in 33 pools, the maximum number estimated to occur within this play. All pools in play 5 are modeled as mixed, that is, containing oil with a gas cap; other plays may also have all-gas or all-oil pools and show six separate commodities. Each pair of gas-oil bars in the play 5 pool rank plot shows the volume of oil in the pool and the volume of gas in the cap. The vertical bars extend across a range of possible volumes for each pool. The lower end of each bar represents the F75 resource quantity, meaning that the pool, if it exists, has a 75-percent chance of exceeding the corresponding resource quantity. Likewise, the upper end of each bar represents the F25 resource quantity. In Chukchi play 5, the largest pool offers oil volumes in the range from about 58 (F75) to 220 (F25) million barrels and gas volumes in the range from 350 (F75) to 1,180 (F25) billion cubic feet.

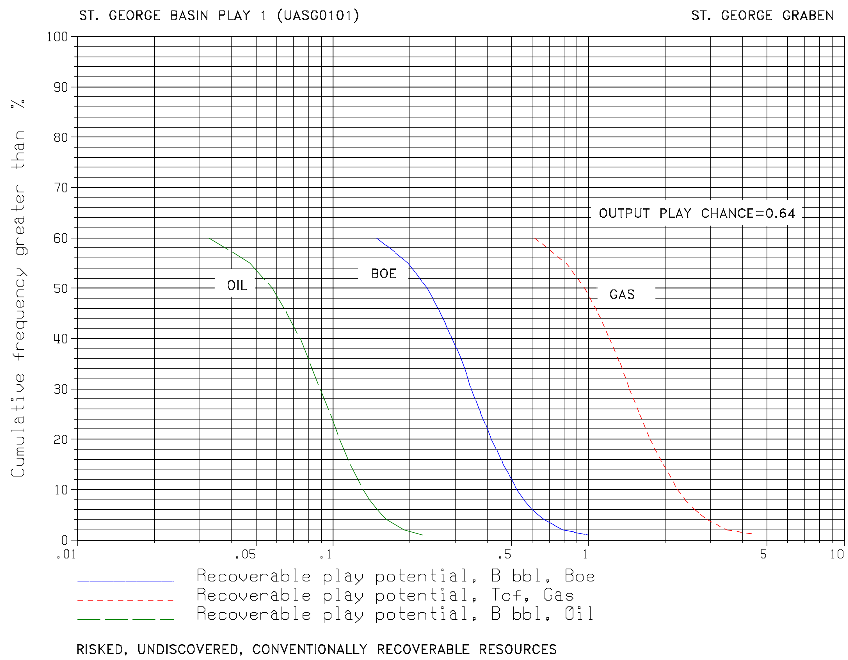
Figure 0.1: Sample play summary, Chukchi shelf play 5.

Extreme sizes outside the range between F75 and F25 volumes are not shown, but all pools offer (at low probabilities) high-side potential that may be several multiples of their median sizes (F50 or centers of vertical bars). For example, the largest pool in the pool rank plot in figure 0.1 shows F75-F25 ranges in oil volumes from 58 to 220 millions of barrels and gas volumes from 350 to 1,180 billions of cubic feet. But, these ranges do not capture the largest possible sizes of pool rank 1. This same pool has a 5-percent chance of containing over 600 million barrels of oil and 3,070 billion cubic feet of gas, or a 1-percent chance of containing over 1,140 million barrels of oil and 6,180 billion cubic feet of gas!

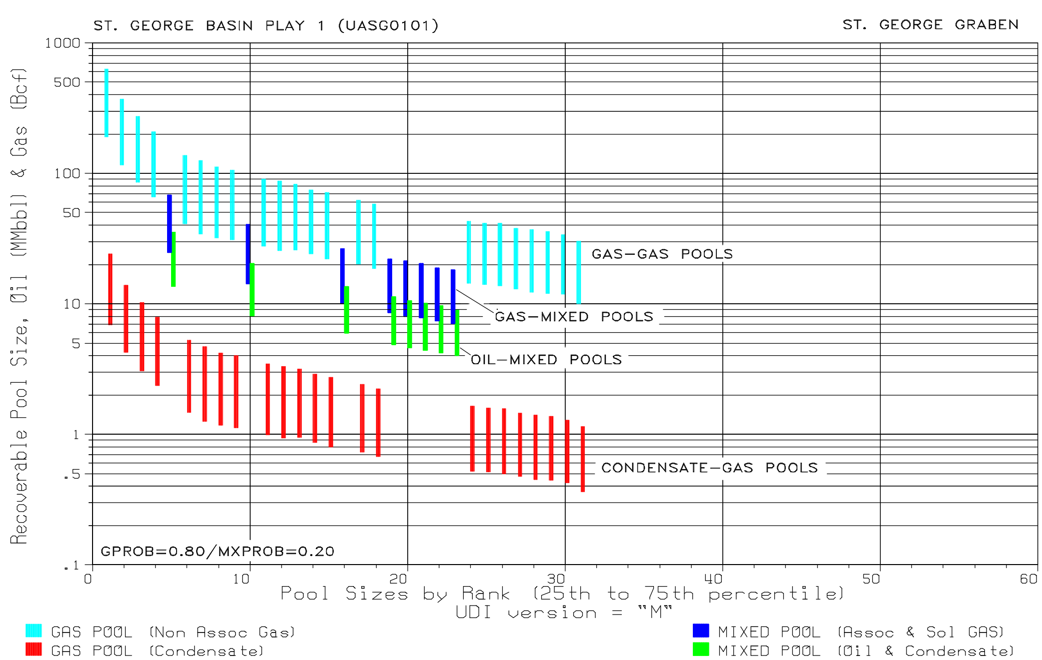
Although it might be interesting to portray the improbable yet extreme-high potential sizes of pools, choosing fractiles ranging up to F01 results in an uninformative plot where all pools nearly reach the top of the plot. For this presentation, a range based on F75-F25 values was chosen for visual clarity while still giving some impression of variance or spread.

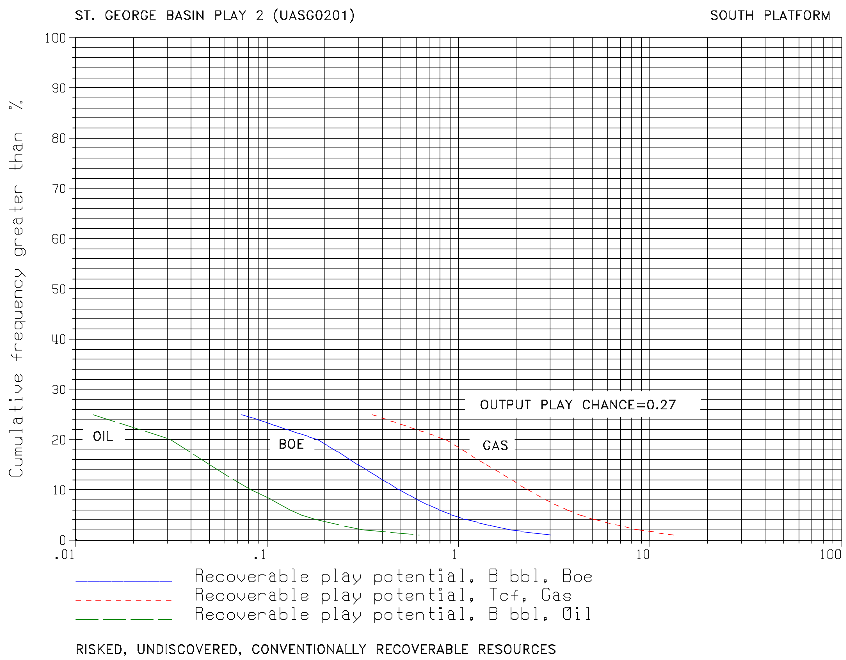
Pool volumes shown in the ranked plots are conditional upon success at the play level (i.e., a hydrocarbon pool existing ***somewhere*** within the play). The sizes of the pools posted in the rank plot have not been "risked", or multiplied against play chance of success. Therefore, except where the play chance of success equals 1.0, the sum of the mean sizes of the pools in the rank plot will exceed the risked mean play endowment that is reported in the table at page center. In fact, several of the largest pools, or even just the largest pool, may post conditional resources exceeding the risked play endowment.

Designation of pool types (oil-only, versus oil with gas cap, versus gas-only) within the play model was controlled by three data entries. Each play was assigned probabilities for (or frequencies of) occurrence of any of three pool types within the play—"OPROB" for oil-only pools, "GPROB" for gas-only pools, and "MXPROB" for mixed (oil and gas cap) pools. As the model recognizes only these three pool types, these three probability values always sum to 1.0. The three probability values control frequency of pool type sampling during ***GRASP*** runs, and, with a random number generator in ***GRASP***, ultimately dictate the sequence of pool types that appear in the play pool rank plots. The OPROB, GPROB, and/or MXPROB values that were used in the play models are posted, as appropriate, in the lower left corner of each pool rank plot.

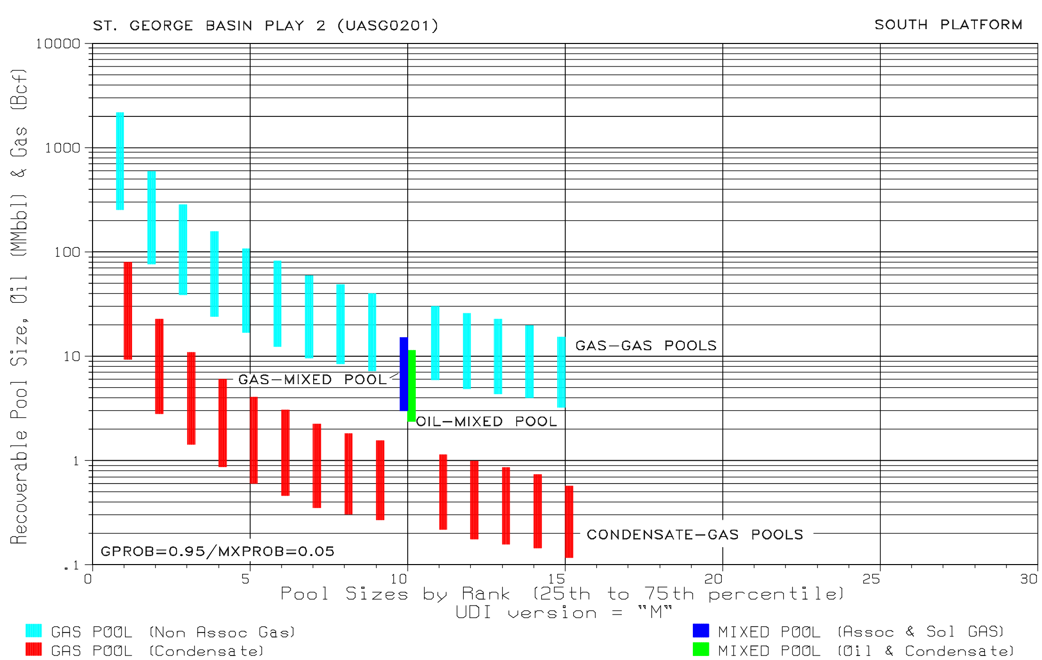


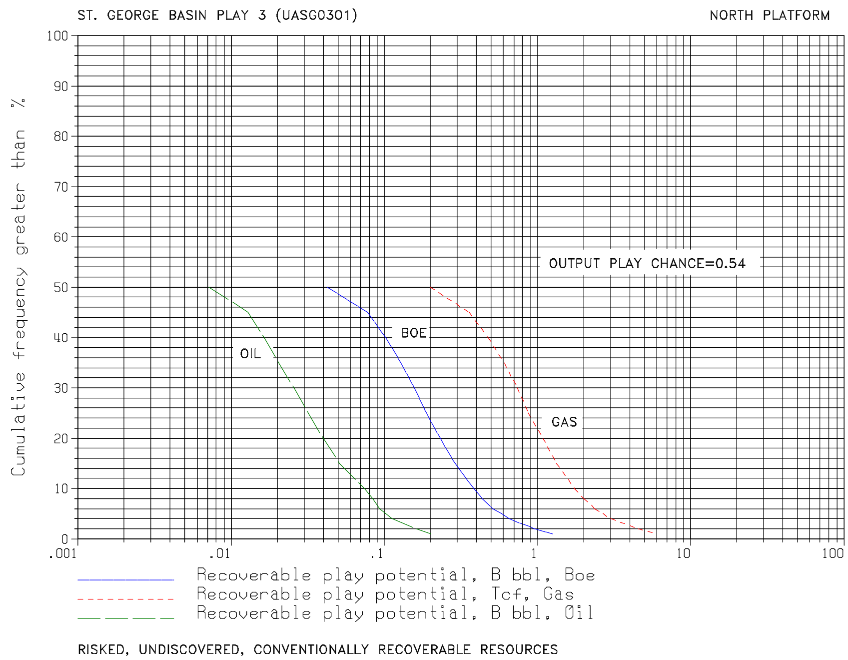
ST. GEORGE BASIN PLAY 1 (UASG0101)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**1.007**	**2.743**
OIL (BBO)	**0.000**	**0.059**	**0.155**
BOE (BBO)	**0.000**	**0.238**	**0.633**



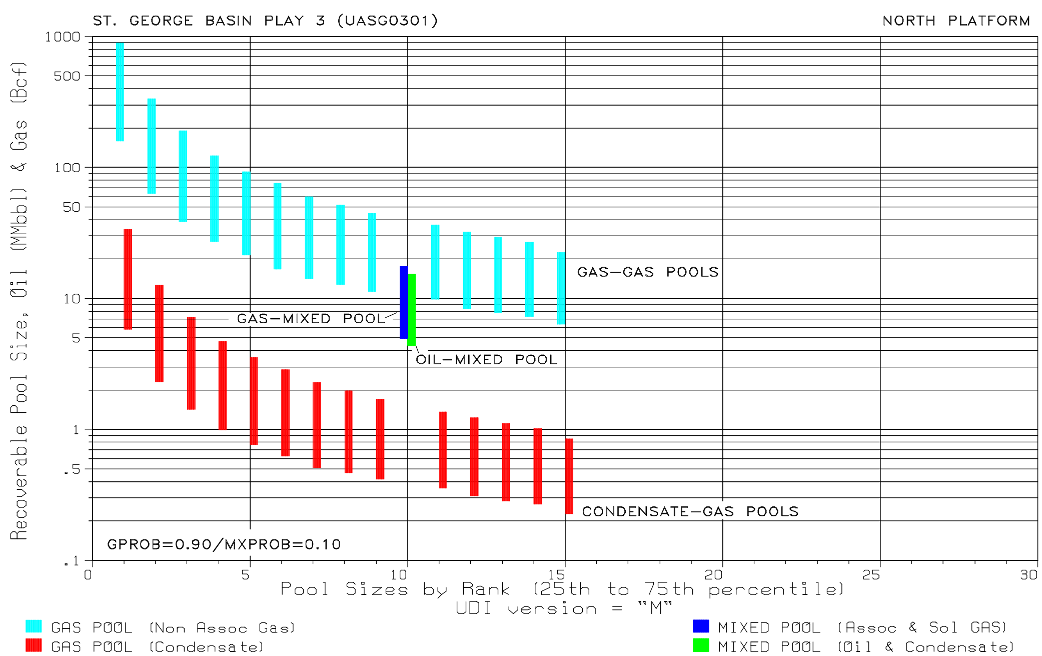


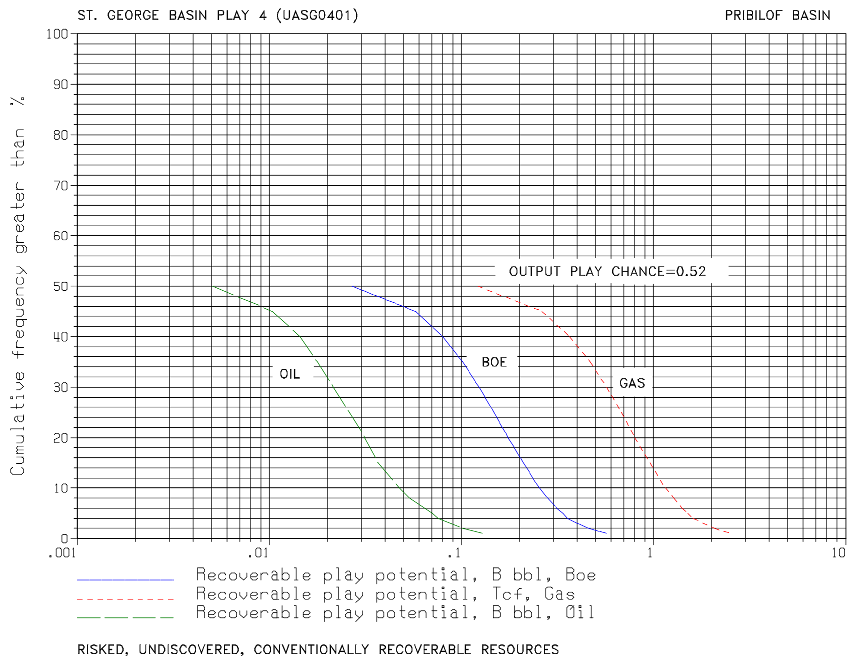
ST. GEORGE BASIN PLAY 2 (UASG0201)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.898**	**4.325**
OIL (BBO)	**0.000**	**0.034**	**0.152**
BOE (BBO)	**0.000**	**0.193**	**0.922**



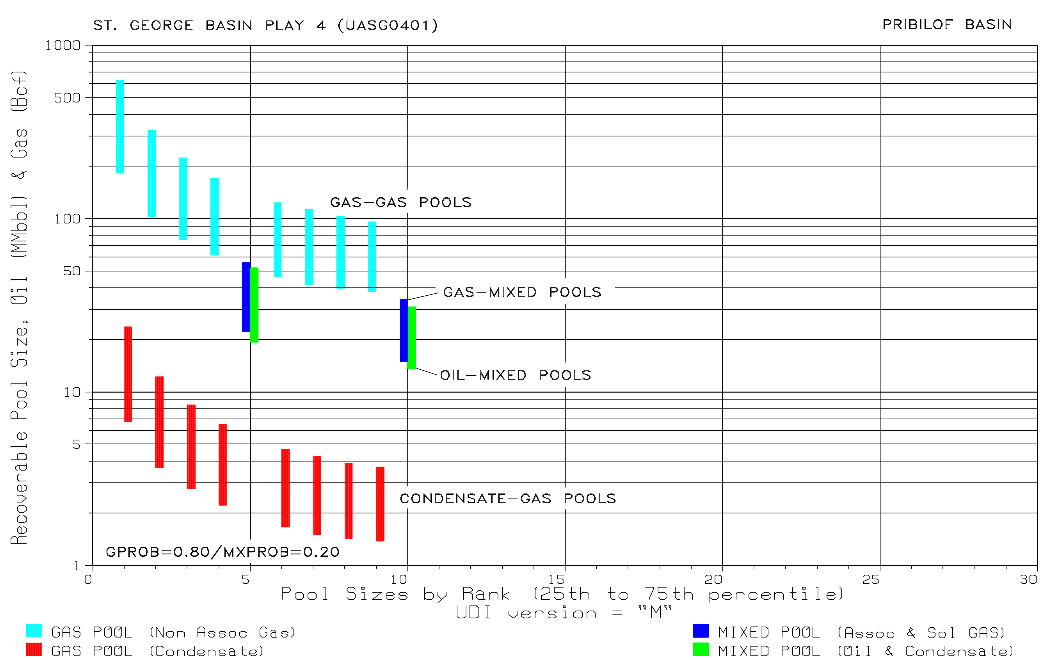


ST. GEORGE BASIN PLAY 3 (UASG0301)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.676**	**2.674**
OIL (BBO)	**0.000**	**0.025**	**0.101**
BOE (BBO)	**0.000**	**0.146**	**0.579**





ST. GEORGE BASIN PLAY 4 (UASG0401)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.414**	**1.502**
OIL (BBO)	**0.000**	**0.017**	**0.070**
BOE (BBO)	**0.000**	**0.091**	**0.337**



ECONOMIC RESULTS, ST. GEORGE BASIN PROVINCE

(James D. Craig)

INTRODUCTION

This section summarizes the results of economic modeling using the *PRESTO-5* (*P*robabilistic *R*esource *EST*imates-*O*ffshore, version 5) computer program. The economic assessment results are influenced, to a large degree, by the undiscovered, conventionally recoverable oil and gas resources assessed using the *GRASP (G*eologic *R*esource *A*ssessment *P*rogram) computer model. The conventionally recoverable results are discussed in separate .pdf files (*Summaries of Play Results, with Cumulative Probability and Ranked Pool Plots*).

Each province summary page includes three illustrations: (1) cumulative probability plots for risked, conventionally recoverable resource distributions (oil, gas, and BOE); (2) a table comparing risked, mean, conventionally recoverable resources with the risked, mean, economically recoverable resources at current commodity prices; and (3) a price-supply graph displaying economically recoverable resource curves.

The province summary page is followed by a table reporting play-specific, economically recoverable resource estimates for two representative price scenarios: a Base Price scenario ($18/bbl-oil, $2.11/MCF-gas) representing current market conditions; and a High Price scenario ($30/bbl-oil, $3.52/MCF-gas).

PROVINCE SUMMARY PAGE

Risked Cumulative Probability Distributions

The province summary page provides, at page top, cumulative probability distributions for risked, undiscovered endowments of conventionally recoverable oil, gas, and BOE, where resource quantities are plotted against "cumulative frequency greater than %." A cumulative frequency represents the probability that the resource endowment is equal or greater than the volume associated with that frequency value along one of the curves. For example, a 95% probability represents a 19 in 20 chance that the resource will equal, or be higher than, the volume indicated. Cumulative frequency values typically decrease as resource quantities increase. An expanded description of cumulative probability plots is given in "*Summaries of Play Results, with Cumulative Probabilities and Ranked Pool Plots* " provided as a separate .pdf file.

Table of Risked Play Resources

The province summary page provides, at page center, a table comparing the total conventionally recoverable endowment and the smaller quantity of economically recoverable resources that could be profitably extracted under current economic and engineering conditions. Current prices are represented as $18 per barrel of oil and $2.11 per MCF of gas, where gas price is linked to oil price by energy equivalency and discount-value factors (5.62 MCF per barrel; 0.66 value discount). Conventional resource volumes correspond to points on the cumulative probability distributions (at page top). Economic resource volumes correspond to points along the mean price-supply curve (at page bottom). Resources listed as negligible (negl) have volumes lower than the significant figures shown. Not Available (N/A) means that these resources are unlikely to be produced in the foreseeable future because of reservoir conditions or the lack of a viable transportation infrastructure.

The ratio of economic to conventional resources indicates the proportion of the total undiscovered endowment that is profitable to produce under current commodity prices with proven engineering technology. However, for production to occur, commercial discoveries must be made, and the analysis does not imply discovery rates. Given the size and geologic complexity of the offshore provinces, exploration will require extensive drilling, and considering the relatively low chance of commercial success and the high cost of exploration wells, many of these frontier provinces are not likely to be thoroughly tested in the foreseeable future. The ratio of economic to conventional resources should be regarded as an opportunity indicator, rather than as a direct scaling factor for readily available hydrocarbon reserves.

Price-Supply Curves

The province summary page includes, at page bottom, a graph showing price-supply curves representing Low, Mean , and High resource production scenarios. Price-supply curves illustrate how volumes of economically recoverable resources increase as a function of commodity price. Characteristically, increases in commodity price result in corresponding increases in economically recoverable resource volumes. The economic resource volumes represent oil and gas, as yet undiscovered, that could be recovered profitably given the modeled economic and engineering parameters. At very high prices, the mean curve approaches the mean total resource endowment estimated by *GRASP*. The price-supply curves do not imply that these resources will be discovered or produced within a specific time frame, only that the opportunity exists for commercial production at levels controlled by commodity prices.

The price-supply curves were generated by the *PRESTO-5* computer program, which simulates the exploration, development, production, and transportation of pooled hydrocarbons in geologic plays within a petroleum province. Economic viability depends on the interaction of many factors defining the size and location of the hydrocarbon pools, the reservoir engineering characteristics, and economic variables relating expenditures to income from future production streams. The economic simulation is quite complex, owing to the complexities in the state of nature, and requires a sophisticated analytical model.

The following is a brief overview of the *PRESTO-5* modeling process. Geologic parameters (for example, reservoir thickness, pool area, risk) used by the *GRASP* computer model to determine conventionally recoverable resources are transferred into the *PRESTO-5* model through an interface program. Economic viability is determined by performing a discounted cash flow analysis on the expenses and modeled production stream for each pool simulated in a given trial. A Monte Carlo (random sampling) process selects engineering parameters (for example, production rate profiles, well spacing, platform installation scheduling), and cost variables (for example, platforms, wells, pipelines) from ranged distributions. Each simulation trial models the expenses, scheduling, and production for pools "discovered" within a particular play. The sampling process is repeated for productive pools in all geologic plays, and the economic resources are aggregated to the province level. The development simulation process is repeated, typically for 1000 trials, at given set of prices (oil and gas prices are linked). After the specified number of trials are completed for the first set of oil and gas prices, a new set of prices is selected and another round of simulation trials is run. This process continues for approximately 30 iterations, yielding a range of economic resource volumes tied to commodity prices. The results for all runs are given as probability distributions, where selected probability levels can be displayed as continuous price-supply curves.

These analyses determine the resource volumes that are commercially viable under a specific set of current economic and engineering assumptions. No attempt was made to upgrade engineering technology or development strategies that might be implemented in response to higher commodity prices.

The price-supply curves provided in this report are based on the most likely development scenario tailored for each particular province. All provinces were modeled on a stand-alone basis, with engineering assumptions designed for the primary hydrocarbon substance (oil or gas) identified by the *GRASP* analysis. Generally, the secondary hydrocarbon is less economically viable and places an extra burden on the primary hydrocarbon substance. For provinces without existing oil and gas infrastructure, the modeling scenarios were designed assuming that the primary substance would drive initial development in a particular province. Oil-prone provinces were modeled as "oil-only" production, with gas reinjected for reservoir pressure maintenance to maximize oil recovery. Gas-prone provinces were modeled with both gas and oil production because natural gas-liquids (or condensates) are not reinjected. Often the volume of condensates in gas-prone provinces exceeds any volume of non-associated crude oil. All hydrocarbon liquids are commingled in production and transportation systems.

This economic analysis assumes 1995 as the base year. Higher <u>nominal</u> commodity prices in the future (price increases only at the rate of inflation) do not result in higher estimated volumes of economically recoverable resources, whereas higher <u>real</u> commodity prices (increases above the rate of inflation) do increase the economically recoverable resources. The economic model assumes that commodity price and infrastructure costs were inflated equally at an assumed 3% annual inflation rate (flat real price and cost paths). The price-supply curves can be used to project economic resource volumes relative to future price if appropriate discounting back to the 1995 base year is made to account for real price and real costs changes in the intervening years.

The price-supply graph usually contains three curves, corresponding to Low, Mean, and High resource production levels. The Low resource case represents a 95% probability (19 in 20 chance) that the resources are equal to, or exceed, the volumes derived from the price-supply curves. The High resource case represents the 5% exceedance level (1 in 20 chance). The Mean resource case represents the average. In high-cost and high-risk provinces, where there are no economically recoverable resources at the 95% probability level, no "Low" curve is displayed. An apparent anomaly is observed in some cases where the lower tail of the "Mean" price-supply curve indicates economic resources greater than the "High" (5% probability) curve. This situation occurs at low prices where the probability of economic success drops below 5%, and the Mean curve is obtained from the few productive trials occurring at probabilities below 5%.

A few additional observations concerning price-supply curves are noteworthy. Following established convention for price-supply curves, these graphs are rotated from the usual mathematical display of X-Y plots. Although shown along the vertical (Y) axis, price is the independent variable and resource is the dependent variable. In many of the gas-prone basins, price-supply curves will display an abrupt step below which no risked economically recoverable resources are modeled. This step corresponds to the minimum resource value required to overcome the cost of production and transportation infrastructure. Because of the distances to Asian markets, the assumed destination for Alaska gas production, natural gas must be converted to liquid form for transportation by ships. The infrastructure associated with conversion into liquefied natural gas (or LNG) does not lend itself to incremental additions for grassroots projects; therefore, an abrupt "cost-hurdle" created by large LNG and marine terminal installations must be overcome by significant resource volumes.

Finally, the reader must be aware that these price-supply curves are models of risked hydrocarbon resources. Both the geologic risk that the resources are pooled and recoverable as well as the economic risk that development is profitable under the assumed economic and technologic conditions are factored into the reported results. This means that although very low resource volumes are reported as "economically recoverable", these low volumes, in fact, do not correspond to actual quantities of oil or gas. At low prices, risk is dominated by economic factors associated with engineering cost and reservoir performance variables. At high prices, risk is dominated by geologic factors related to volumetric variables. **Risked price-supply curves are most appropriately used to define the comparative potential of petroleum provinces under changing price and probability conditions.** They do not predict the timing of resource discovery or rate of conversion of undiscovered resources to future production. As previously stated, future production of the modeled economically recoverable resources will require extensive exploration programs. In the Alaska offshore, future leasing and exploration activities are likely to be driven by "high-side potential", combining perceptions of greater rewards at higher risk, higher future commodity prices, and innovative technology to reduce costs.

TABLE FOR PLAY RESOURCE DISTRIBUTIONS

The risked mean contribution for each geologic play in the province is tabulated under two hypothetical price conditions. The Base Price ($18 per barrel-oil; $2.11 per MCF-gas) represents current economic conditions. The High Price ($30 per barrel-oil; $3.52 per MCF-gas) represents a situation where real price has increased significantly from current levels. Other economic parameters (for example, discount rate and corporate tax rate) were equal in both scenarios, as were engineering technology and cost assumptions. The play number, name, and *UAI* (*U*nique *A*ssessment *I*dentifier code) provide a link to the data presented in other sections of this report. Hydrocarbon substances are distinguished as oil (includes crude oil and gas-condensate liquids), gas (includes non-associated, associated, and dissolved gas), and BOE (gas volume is converted to barrel of oil equivalent and added to oil volume).

ST. GEORGE BASIN MODELING RESULTS

The St. George basin province was modeled for the simultaneous production of gas and oil resources. Natural gas, as the dominant hydrocarbon, is assumed to support the development activities in the province, with crude oil and natural gas liquids (condensates) recovered utilizing gas production platforms. As there is no petroleum infrastructure in the Bering Sea, new transportation facilities are required both in the province as well as on the Alaska Peninsula.

The development scenario assumes that gas produced from floating offshore platforms would be transported by a 340 mile subsea pipeline to a new facility in Balboa Bay on the south side of the Alaska Peninsula where it will be converted to liquefied natural gas (LNG). LNG would be shipped by marine carriers to markets in Japan or other Pacific Rim countries. Using a great-circle tanker route, Balboa Bay is 3000 miles from the assumed landing port in Japan (Yokohama). Natural gas liquids and crude oil would be transported by pipeline to a offshore storage and loading terminal at a central location between producing fields. Ice-reinforced tankers would shuttle commingled oil and condensate to a transshipment terminal at Balboa Bay, continuing by conventional tankers to West Coast markets (Los Angeles).

Under the Base Price condition ($2.11 per MCFG), the St. George basin province contains an estimated 0.05 TCFG of risked mean economically recoverable gas and a negligible volume of economically recoverable oil. At the High Price condition ($3.52 per MCFG), the province contains 0.10 TCFG of economically recoverable gas, representing only 3.4% of the mean conventionally recoverable gas endowment (3.0 TCFG). The poor economic viability is attributed to relative small pool sizes and high development and transportation costs for gas production. The development cost hurdle is overcome at a gas price of approximately $8.00 per MCFG, above which significant volumes (greater than 1.0 TCFG) of gas resources are recoverable only in the High resource case. For example, at $10.50 per MCFG (roughly three times the current overseas LNG price), there is a 5% chance (1 in 20) that 5.8 TCFG would be economic to produce from the St. George Basin. This optimistic price and production scenario would require a substantial increase in real gas prices as well as an aggressive exploration program to discover these resources. It is very unlikely that oil reservoirs will be developed in the St. George basin unless they can be developed from platforms installed for gas production.

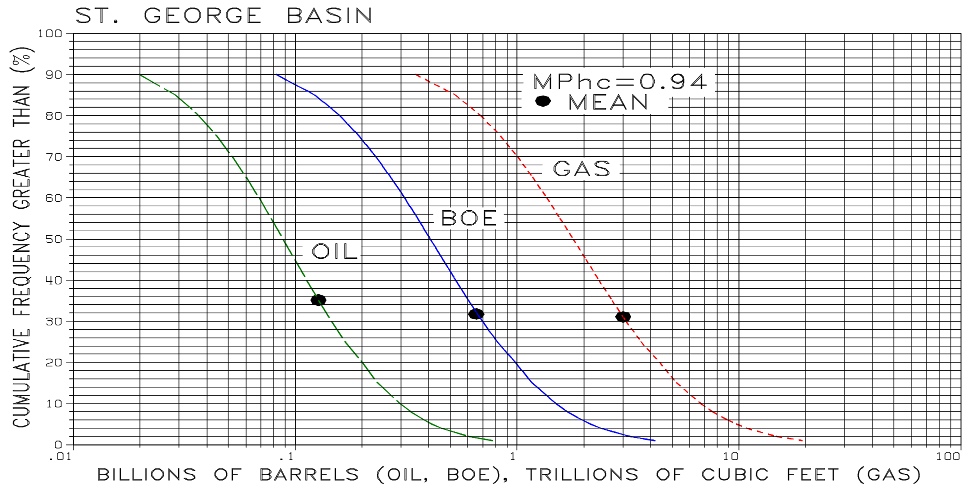
Gas resources in the St. George Basin occur in 4 geologic plays, however, one play (South Platform, Play 2) contains most of the economically recoverable gas resources under both price conditions (90% at Base Price and 82% at High Price). The province has been tested by a total of 10 exploration and 2 stratigraphic test wells, and 6 wells were located in the South Platform play area. All exploration wells were plugged and abandoned without encountering significant hydrocarbon shows. The dominance of Play 2 is explained by large, easily identified structures and abundant reservoir sands, contributing to gas pool sizes ranging up to 2.3 TCFG (mean).

Gas production from the St. George basin province is very unlikely on a stand-alone basis because of the high costs associated with gas transportation infrastructure. However, co-development strategies with adjacent provinces might improve the economic opportunity in this province. For example, a subsea gas pipeline and LNG facility on the Alaska Peninsula built for other Bering Sea provinces (Navarin, North Aleutian) could be utilized by later development in the St. George basin, thereby lowering the initial infrastructure cost. Future exploration interest is likely to be driven by the high-side potential (which accepts higher rewards at higher risks), particularly focused on the untested structures in the South Platform area (Play 2).

Economic Results for St. George basin assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources** ; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic gas** at mean and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

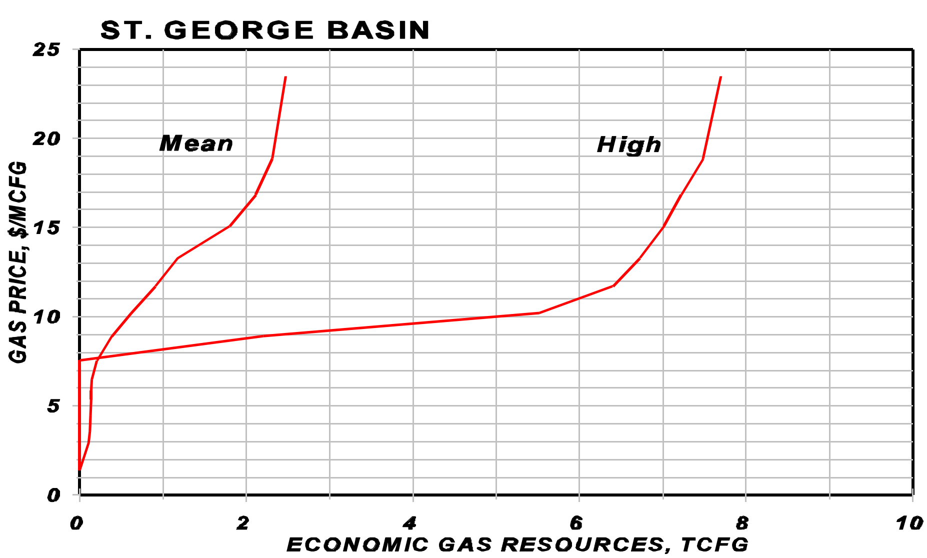
A.



B.

ST. GEORGE BASIN PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	0.13	3.00
ECONOMICALLY RECOVERABLE ($18)	negl	0.05
RATIO ECONOMIC/CONVENTIONAL	negl	0.02

C.



OIL AND GAS RESOURCES OF ST. GEORGE BASIN PLAYS
Risked, Undiscovered, Economically Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI * CODE)	BASE PRICE			HIGH PRICE		
		OIL	GAS	BOE	OIL	GAS	BOE
1.	St. George Graben (UASG0101)	0.000	0.000	0.000	negl	0.004	0.001
2.	South Platform (UASG0201)	0.002	0.044	0.009	0.003	0.084	0.018
3.	North Platform (UASG0301)	negl	0.004	0.001	0.001	0.013	0.003
4.	Pribilof Basin (UASG0401)	negl	0.001	negl	negl	0.002	negl
	TOTAL	***0.002***	***0.049***	***0.010***	***0.004***	***0.103***	***0.022***

* *Unique Assessment Identifier, code unique to play.*

OIL is in billions of barrels (BBO). **GAS** is in trillion cubic feet (TCF).
BOE is barrel of oil equivalent barrels, where 5,260 cubic feet of gas = 1 equivalent barrel-oil

For direct comparisons among provinces, two prices are selected from a continuum of possible price/resource relationships illustrated on price-supply curves. **BASE PRICE** is defined as $18.00 per barrel for oil and $2.11 per thousand cubic feet for gas. **HIGH PRICE** is defined as $30.00 per barrel for oil and $3.52 per thousand cubic feet for gas. Both economic scenarios assume a 1995 base year, flat real prices and development costs, 3% inflation, 12% discount rate, 35% Federal corporate tax, and 0.66 gas price discount.

Shaded columns indicate the most likely substances to be developed in this province. Economic viability is indicated on price-supply curves which aggregate the play resources in each province.